0000089347

APS A subsidiary of Pinnacle West Capital Corporation

Barbara Klemstine
Director
Regulation and Pricing

Tel. 602-250-4563
Fax 602-250-3003
e-mail Barbara.Klemstine@aps.com

Mail Station 9708
PO Box 53933
Phoenix, Arizona 85072-3999

ORIGINAL

October 10, 2008

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: Arizona Public Service Company's Comments
Resource Planning Draft Rules
DOCKET NO. E-00000E-05-0431

Dear Madam or Sir:

Arizona Public Service Company ("APS") is providing the attached comments regarding the Draft Resource Planning Rules that were provided by Staff at the Resource Planning Workshop, held on October 3rd, 2008. This filing includes APS comments on all portions of the Draft Resource Planning Rules with the exception of Section 705 Procurement. APS comments on Section 705 Procurement, will be filed in a subsequent filing.

If you have any questions or wish to discuss these matters further, please call Jeff Johnson at 602-250-2661.

Sincerely,

Barbara Klemstine

Barbara Klemstine

Attachment

BK/dst

Cc: Ernest Johnson
Terri Ford
Barbara Keene
Parties of Record

Arizona Corporation Commission
DOCKETED
OCT 10 2008
DOCKETED BY MM

RECEIVED
2008 OCT 10 P 3: 34
AZ CORP COMMISSION
DOCKET CONTROL

Copies of the foregoing were emailed or mailed
this 10th day of October, 2008.

Ms. Lyn Farmer
Chief Administrative Law Judge, Hearing
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Mr. Ernest Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Ms. Janice Alward
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Mr. Jeff Schlegel
SWEEP
1167 W. Samalayuca Drive
Tucson, Arizona 85704

Mr. Robert Annan
The Annan Group
6605 East Evening Glow
Scottsdale, Arizona 85262

Mr. Dave Couture
Tucson Electric Power
PO Box 711
Tucson, Arizona 85702

Mr. David Berry
Western Resource Advocates
PO Box 1064
Scottsdale, Arizona 85252

Mr. Eric C. Guidry
Western Resource Advocates
2260 Baseline, Suite 200
Boulder, Colorado 80302

Mr. Jerry Coffey
Mr. Erick Bonner
Ms. Rebecca Turner
Gila River Power, L.P.
702 North Franklin Street
Tampa, Florida 33602

Mr. Arthur N. Olson
Technology, Energy & Marketing Strategies
PO Box 21446
Mesa, Arizona 85277

Ms. Karen Haller
Southwest Gas Corporation
5421 Spring Mountain Road
Las Vegas, Nevada 89102

Mr. Paul R. Michaud
Michaud Law Firm, P.L.C.
46 Eastham Bridge Road
East Hampton, Connecticut 06424

Mr. Stan Barnes
Copper State Consulting Group
3033 N. Central Ave., 9th Floor
Phoenix, Arizona 85012

Mr. Larry Killman
Greystone Environmental
401 West Baseline Road, Suite 204
Tempe, Arizona 85283

Mr. Michael Patten
Ms. Laura Sixkiller
Roshka DeWulf & Patten
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Mr. Roger Clark
Grand Canyon Trust
2601 N. Fort Valley Road
Flagstaff, AZ 86001

Amanda Ormond
The Ormond Group, LLC
7650 S. McClintock Drive, Suite 103-282
Tempe, Arizona 85284

Mr. Michael Grant
Galagher & Kennedy
2575 East Camelback Road
Phoenix, Arizona 85016

Mr. C. Webb Crockett
Mr. Patrick J. Black
Fennemore Craig
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012

Mr. Jerry Payne
Cooperative International Forestry
333 Broadway SE
Albuquerque, New Mexico 87102

Mr. Brian Hageman
Ms. Caren Peckerman
Mr. Richard Brill
Deluge, Inc.
4116 East Superior Avenue, Suite D3
Phoenix, Arizona 85040

Mr. Jay Moyes
Moyes Storey
1850 North Central Avenue, Suite 1100
Phoenix, Arizona 85004

Mr. Daniel Pozefsky
Mr. Stephen Ahern
RUCO
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007

Mr. John Wallace
Grand Canyon State Electric Cooperative
Association, Inc
120 North 44th Street, Suite 100
Phoenix, Arizona 85034

Mr. Dan Austin
Comverge, Inc.
6509 West Frye Road, Suite 4
Chandler, Arizona 85226

Mr. Steven B. Bennett
Deputy City Attorney
City Attorney's Office
City of Scottsdale
3939 N. Drinkwater Blvd
Scottsdale, Arizona 85251

Mr. Charlie Emerson
Manager of Technical Services
TRICO Electric Cooperative
8600 W. Tangerine Road
Marana, AZ 85653

Mr. Greg Patterson
Arizona Competitive Alliance Power
916 W. Adams Street, Suite 3
Phoenix, AZ 85007

Mr. Ned Farquhar
Natural Resources Defense Council
1414 Camino Amparo NW
Albuquerque, NM 87107

Ms. Jana Brandt
Ms. Kelly Barr
Salt River Project
PO Box 52025, MS PAB221
Phoenix, Arizona 85072

Mr. Sean Seitz, President
Arizona Solar Energy Industries
Association (AriSEIA)
3008 North Civic Center Plaza
Scottsdale, AZ 85251

Mr. Clifford A. Cathers
Sierra Southwest Cooperative Services, Inc
1000 South Highway 80
Benson, Arizona 85602

Mr. Troy Anatra
Comverge, Inc
120 Eagle Rock Avenue, Suite 190
East Hanover, New Jersey 07936

Resource Planning Workshop
Docket No. E-00000E-05-0431
Arizona Public Service Company Comments
October 10, 2008

Introduction

On September 15, 2008, Arizona Public Service ("APS" or "Company") filed comments to address the proposed modifications that Commission Staff had previously presented ("September Filing") in the Commission's Resource Planning workshop. At the October 3, 2008 workshop, Staff presented an updated Working Document ("Second Working Document") that incorporated some of the recommendations made by interested parties, and indicated that they had not fully considered the comments previously provided by the various parties. Staff encouraged parties to file follow-up comments by October 10, 2008 (October 17, 2008 for comments on the procurement section of the proposed rules). These comments are provided by APS in response to Staff's request.

In this filing, the Company is addressing only the most essential unresolved issues to avoid redundancy with its previous comments. The most critical issues are: 1) the importance of an acknowledgement finding and the weight that such a finding is given in subsequent Commission proceedings; 2) the necessity of a broader decisional criterion than merely a "least-cost" standard to assess a resource plan; and 3) the applicability of proposed Resource Planning Rules to all load-serving entities, including competitive Electric Service Providers ("ESPs"). The Company has attached a redlined version of the Second Working Document that incorporates the proposed modifications discussed in this filing ("Second APS Redline"). The Company continues to support all of the recommendations it made in its September Filing, including those that are not restated in this document.

To meet the long-term needs of Arizona electric customers, a collaborative resource planning process that involves the Commission, the utilities and other interested parties is required. Resource Planning Rules must assure that a diverse portfolio of resources has been analyzed, that the basis and outcome of the analyses is available for the public, and that sufficient regulatory certainty is provided so the electric utilities can proceed with major long-term resource plans to assure reliable electric service in the future. These goals are the basis for APS's recommendations for Resource Planning Rules.

Commission Acknowledgement of Reasonableness of Utility's Resource Plans

As stated in its September Filing, APS believes that Staff's proposed modifications to the final outcome of the Integrated Resource Planning ("IRP") process is a significant improvement over the mere "consistency finding" embodied in the current rules. A resource planning process that allows for an evidentiary hearing, and results in a formal Commission decision that acknowledges that the utility's long-term planning choices were reasonable at the time that the Commission's determination was made, would provide an increased level of regulatory certainty. This process would provide the public with an understanding of utilities' long-term resource planning and acquisition process, and the Commission's acknowledgement of the resource plan would provide the public with confidence that a reasonable long-term resource plan will be executed to meet their future energy needs.

Because of the magnitude of financial commitments involved in the acquisition of generation, it is essential that the Commission concurs with a utility's proposed long-term resource plan before a utility must undertake significant infrastructure additions. Therefore, APS believes that the proposed Resource Planning Rules should be further modified to clarify that when the Commission acknowledges the reasonableness of a resource plan, the acknowledgement will be given considerable weight in subsequent Commission proceedings.

As discussed at length in APS's September Filing, the Oregon Public Utility Commission ("PUC") has specifically addressed this issue and determined that while a resource planning acknowledgement did not constitute ratemaking, it was relevant to the ultimate question of rate-making treatment.[1] In ratemaking proceedings where the reasonableness of resource acquisitions is considered, the Oregon PUC gives considerable weight to utility actions that are consistent with acknowledged integrated resource plans.[2] APS believes that the Oregon PUC has taken a judicious approach that appropriately addresses the regulatory certainty that is necessary to pursue sizeable generation resources.

APS urges the Commission to adopt a similar approach. To that end, the Company proposes that three modifications be made to the Second Working Document:

1. Add a definition of the term "Acknowledgment" to provide further clarity and certainty. The Company proposes the following language:

   > "Acknowledgement" – the Commission's finding of the reasonableness of a utility's plan that is based upon a determination that the plan considered all relevant resources, risks and uncertainties known or knowable, and produces a plan for needed resources that is in the best interests of customers at the time of the Commission's determination.

2. Add the following as factors that the Commission will consider in making its acknowledgment determination:[3]

   - The degree to which a utility considered all relevant resources, risks and uncertainties.
   - The degree to which the utility's plan for future resources is in the best interest of customers.

[1] *See,* Oregon PUC Order No. 07-002 (Jan. 8, 2007) at 24.
[2] *See,* Oregon PUC Order No. 08-232 (Apr. 24, 2008) at 38.
[3] These factors would be included in section R14-2-704(C) of the Second Working Document.

3. Add specific language that states:

> "The Commission will give considerable weight to the utility's actions that are consistent with an acknowledged integrated resource plan in a rate case or other proceeding before the Commission".[4]

Tucson Electric Power ("TEP"), UNS Electric, and Western Resource Advocates ("WRA") supported this approach in their comments filed in September.

Resource Planning Decisional Criteria

APS believes that the Resource Planning Rules should recognize that "least-cost" is not the decisive factor for selecting the best portfolio of resources. Given some of the issues that are currently facing the electric industry, such as complex environmental issues, the least-cost standard may not always be the best long-term choice for the utility, its customers or the state. When evaluating all potential resources, there are other criterion that should be taken into account, which include increasing the diversity, reliability, and environmental benefits of utility resources and promoting stable electricity prices. There are more qualitative factors, such as risk, project viability and the impact on public health, that should also be considered.

APS recommends that the following factor be included for Commission consideration in making an acknowledgement determination:

> The best combination of expected costs and associated risks and uncertainties for the utility and its customers.[5]

WRA, TEP and UNS Electric's comments filed in September reflect their agreement that resource planning has multiple goals, should not limited to the minimization of costs, and that the evaluation of financial, regulatory, environmental and operational risks for various resource options should be considered.

Applicability

The Second Working Document has retained the applicability requirement found in the current Resource Planning Rules—specifically that the rules apply to all jurisdictional electric utilities that own or operate generating facilities, whether the power is generated for sale to end users or is for resale.[6] APS strongly believes that the requirement to "own or operate generating facilities" may exclude entities that purchase power in the market and resell it to retail customers, including competitive Electric Service Providers. APS's position is analogous to that of TEP

---

[4] This language would be included in section R14-2-704(A) of the Second Working Document.
[5] This factor would be included in section R14-2-704(C) of the Second Working Document.
[6] The Second Working Document has narrowed that requirement to ownership of generating facilities of at least 5 MW combined.

and UNS Electric, who have proposed that the Resource Planning Rules be applicable to "Load Serving Entities."[7]

Including all entities that serve customers under the Resource Planning Rules is particularly relevant in light of the Commission's recent decision to commence workshops to determine whether retail electric competition is in the public interest.[8] APS believes that applicability of the Resource Planning Rules must extend to all electric utilities that are under the jurisdiction of the Commission, so that the adequacy of each electric provider's portfolio can be assessed in terms of service reliability, energy source diversity, and risks, among other things. That being said, APS does support a modified resource planning approach for entities with a lesser amount of retail load, as was discussed at the October 3rd workshop. The Company believes that the appropriate threshold for this "IRP-lite" approach would be entities with less than one million megawatt hours of retail load annually.[9] Rather than the full detailed analyses required of larger providers, these entities should be required to file resource plans that include load forecast, outlook for existing resources, and future expected resource additions, as well as describe how their plan provides adequate levels of reliability and addresses risks and uncertainty.

By applying the Resource Planning Rules to all load-serving entities, the Commission would be assured that the future needs of all customers are considered, and that a reasonable resource plan is in place to assure reliable future electric service.

<u>Other Considerations</u>

Three Year Action Plans. To accommodate the two-year filing, review and hearing cycles proposed by Staff, the action plan that is required as part of the IRP should be a three year action plan.

Amendments to Resource Plan. The rules should include a provision that allows a utility to file amendments to its acknowledged integrated resource plan and action plan, if material changes in conditions or assumptions require a material change before the next scheduled integrated resource plan filing.

Competitively Confidential Information. The Resource Planning Rules should specifically acknowledge that confidential information furnished to the Commission in compliance with these rules would not be made public. Similar language is found in Arizona law[10] and included in the Commission's Affiliated Interest Rules.[11]

---

[7] The Retail Electric Competition Rules define "Load Serving Entity" as "An Electric Service Provider, Affected Utility, or Utility Distribution Company, excluding a Meter Service Provider, and Meter Reading Service Provider." A.A.C. R14-2-1601(23).

[8] At the Commission's August 27, 2008 Open Meeting, the Commission voted to reexamine retail electric competition through a workshop process. *See* Decision No. 70485 (Sept. 3, 2008).

[9] This would equate to a peak load of approximately 250 megawatts, based on a fifty percent load factor utility.

[10] A.R.S. Section 40-204(C) provides broad confidentiality protections for information a company files with the Commission.

[11] A.A.C. R14-2-1802(B).

Work Plan Requirements. The Second Working Document includes a requirement that the utility provide its method and assumptions for assessing potential resources twelve months before the filing of its IRP. The Resource Planning Rules should recognize that certain assumptions, such as natural gas prices, will quickly become stale. Therefore, the requirement at the early stage that the work plan is filed should be for "current assumptions" or "assumptions without values and source."

Conclusion

APS urges Staff to make the modifications and clarifications discussed above to assure that the Resource Planning Rules provide a practical, effective and efficient tool for long-term resource planning and competitive procurement solicitations.

APS'S REVISIONS TO STAFF'S SECOND WORKING DOCUMENT

(All changes indicated in Staff's 10/3/08 Working Document were "accepted" prior to including APS's proposals in this draft.)

October 3, 2008

ARTICLE 7. RESOURCE PLANNING

R14-2-701. Definitions

The following definitions shall apply unless the context otherwise requires:

1. "Acknowledgement" - the Commission's finding of the reasonableness of a utility's plan that is based upon a determination that the plan considered all relevant resources, risks and uncertainties known or knowable, and produces a plan for needed resources that is in the best interests of customers at the time of the Commission's determination.

~~1~~2. "Benchmark" - to calibrate against a known set of values or standards.

~~2~~3. "Book life" - the expected time period over which a power supply source will be available for use by the utility.

~~3~~4. "Capacity" - the amount of electric power in megawatts ("MW") which a power source is rated.

~~4~~5. "Capital costs" - the construction and installation cost of facilities including land, land rights, structures, and equipment.

~~5~~6. "Cogeneration" - the production of electrical energy and another form of useful energy, such as heat or steam, from the sequential use of energy.

~~6~~7. "Coincident peak" - the sum of two or more peak demands which occur in the same demand interval. Demand intervals are defined on an annual, monthly, or hourly basis.

~~7~~8. "Customer class" - a group of customers with similar characteristics such as amount of energy consumed; amount of demand placed on the energy supply system at the system peak; hourly, daily, or seasonal load pattern; type of activity engaged in by the customer; and location. Customer classes may include residential, commercial, industrial, agricultural, municipal, and other categories.

~~8~~9. "Decommissioning" - the process of safely and economically removing a unit from service.

~~9~~10. "Demand management" - beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time the demand for electricity.

~~10~~11. "Derating" - reduction in a unit's capacity.

~~11~~12. "Discount rate" - the interest rate used to calculate the present value of a cost or other economic variable.

~~12~~13. "Emergency" - an unknown and unforeseeable condition (i) not arising from acts or omissions by the utility which are not in accord with good utility practice, (ii) that is temporary in nature, (iii) that threatens reliability or poses some other significant risk to the system, and (iv) where the subject procurement is not greater in quantity or duration than what is necessary for the utility to restore the system to a safe and reliable condition.

~~13~~14. "End use" - the final application of electric energy such as heating, cooling, running a particular appliance, or lighting.

~~14~~15. "Energy losses" - electric energy not available for sale to end users, for resale, or for use by the utility, attributable to transmission, conversion, distribution, and unaccounted for losses.

~~15~~16. "Escalation" - the change in costs due to inflation, changes in manufacturing processes, availability of labor or materials, or other factors.

~~16~~17. "Heat rate" - a measure of generating station thermal efficiency expressed in British thermal units (Btus) per net kilowatt-hour and computed by dividing the total Btu content of fuel used for electric generation by the kilowatt-hours of electricity generated.

~~17~~18. "Interruptible power" - power made available under agreements which permit curtailment or cessation of delivery by the supplier.

~~18~~19. "In-service date" - the date a power supply source becomes available for use by the utility.

~~19~~20. "Maintenance" - the repair of generation, transmission, distribution, and administrative and general facilities, replacement of minor items, and installation of materials to preserve the efficiency and working condition of the facilities.

~~20~~21. "Mothballing" - the temporary removal of a unit from active service and accompanying long-term storage activities.

~~21~~22. "Operate" - to manage or otherwise be responsible for the production of electricity from a generating facility, whether that facility is owned by the operator, in whole or in part, or whether that facility is owned by another entity.

~~22~~23. "Operating costs" - the power production costs that are directly related to producing electricity.

~~23~~24. "Participation rate" - the proportion of customers who take part in a specific program.

~~24~~25. "Probabilistic analysis" - a systematic evaluation of the effect on costs, reliability, or other measures of performance of the range of possible events affecting factors which influence performance, considering the chances that the events will occur.

~~25~~26. "Production cost" - the variable operating and maintenance cost (including fuel cost) of producing electricity through generation and purchases of power sufficient to meet demand.

~~26~~27. "Refurbish" - to make major changes in the power production, transmission, or distribution characteristics of a component of the power supply system more extensive than maintenance or repair, such as changing the fuels which can be used in a generating unit or changing the capacity of a generating unit.

~~27~~28. "Reliability" - a measure of the ability of the utility's generation, transmission, and distribution systems to provide power without failures. Reliability should be measured separately for generation, transmission, and distribution systems. Measures may reflect the proportion of time that each system is unable to meet demand or the kilowatt-hours of demand that could not be supplied.

~~28~~29. "Reserve requirements" - the capacity which the utility must maintain in excess of its peak load to provide for scheduled maintenance, forced outages, unforeseen loads, emergencies, system operating requirements, and reserve sharing arrangements.

~~29~~30. "Resource planning" - integrated supply and demand analysis for the purpose of identifying the means of meeting electric energy service needs at the lowest total cost, taking into account uncertainty.

~~30~~31. "Self generation" - the production of electricity by an end user by any means including cogeneration.

~~31~~32. "Sensitivity analysis" - a systematic assessment of the degree of response of costs, reliability, or other measures of performance to changes in assumptions about factors which influence performance.

~~32~~33. "Spinning reserve" - the capacity which the utility must maintain connected to the system and ready to deliver power promptly. The capacity may be expressed as a percentage of peak load, as a percentage of the largest unit, or as fixed megawatts.

~~33~~34. "Staff" - Employees of the Arizona Corporation Commission, Utilities Division.

~~34~~35. "Total cost" - all capital, operating, maintenance, fuel, and decommissioning costs incurred in the provision or conservation of electric energy services borne by end users, utilities, or others, and costs associated with mitigating any adverse environmental effects.

~~35~~36. "Unit" - a specific device or set of devices that converts one form of energy (such as heat or solar energy) into electric energy such as a turbine and generator or set of photovoltaic cells; a power plant may have multiple units.

~~36~~37. "Utility" - the public service corporation providing electric service to the public, unless otherwise provided herein.

R14-2-702. Applicability

A. All electric utilities under the jurisdiction of the Commission pursuant to Arizona Constitution Art. XV and Arizona Revised Statutes Title 40 ~~which operate or own (in part or in whole) generating facilities of at least 5 MW combined, whether the power generated is for sale to end users or is for resale,~~ are subject to the provisions of this Article. Filing requirements for a utility with less than one million megawatt hours of annual retail load may be modified. ~~It is not the intent of these rules to apply to electric utilities which do not own generation facilities.~~

~~B. Any other electric utility under the jurisdiction of the Commission pursuant to Arizona Constitution Art. XV and Arizona Revised Statutes Title 40 is subject to the provisions of this Article upon two years' notice by the Commission.~~

~~C~~B. The Commission may exempt a utility from these requirements upon a demonstration by the utility that the burden of compliance with this Article exceeds the potential for cost savings resulting from its participation.

R14-2-703. Utility reporting requirements

A. Historical demand-side data. Each utility shall file in Docket Control the demand data indicated in subsections (A)(1) through (4) below, by April 1 of each year. If records are not maintained for any item, the utility shall provide its best estimates, such as sample survey data, application of factors from one year's data to another year, or other methods, and fully describe how such estimates were made.

1. Hourly demand for the previous calendar year disaggregated by:
   a. Sales to end users,
   b. Sales for resale,
   c. Energy losses, and
   d. Other disposition of energy such as energy furnished without charge and energy used by the utility.
2. Coincident peak demand (megawatts) and energy consumption (megawatt-hours) by month for the previous ten years disaggregated by customer class.

3. Number of customers by customer class by year for the previous ten years.
4. Reduction in load (kilowatt and kilowatt-hours) due to existing demand management measures, by type of demand management measure, in the previous calendar year.

B. Historical supply-side data. Each utility shall file in Docket Control the supply data indicated in subsection (B)(1) through (4) by April 1 of each year. If records are not maintained for any item, the utility shall provide its best estimates and fully describe how those estimates were made.

1. For each generating unit and purchased power contract for the previous calendar year:
   a. In-service date and book life or contract period,
   b. Type of generating unit or contract,
   c. Capacity in megawatts (utility share),
   d. Maximum unit or contract capacity by hour, day, or month, if such capacity varies over the year.
   e. Annual capacity factor (generating units only),
   f. Average heat rate of generating units and, if available, heat rates at selected output levels,
   g. Fuel cost for generating units in dollars per million Btu for each type of fuel,
   h. Other variable operating and maintenance costs for generating units in dollars per megawatt hour,
   i. Purchased power energy costs for long-term contracts of three years or more expressed in dollars per megawatt-hour,
   j. Fixed operating and maintenance costs of generating units in dollars per megawatt for the year,
   k. Demand charges for purchased power,
   l. Fuel types for generating units,
   m. Minimum capacity at which the unit would be run or power must be purchased,
   n. Whether, under standard operating procedures, the generating unit must be run if it is available to run,
   o. Description of the expected duty cycle of a generating unit, such as base load, intermediate, or peaking. p. Environmental impacts, including air emission quantities (metric tons or pounds) and rates (quantities per megawatt-hour) for carbon dioxide, nitrogen oxides, mercury, particulates, and other air emissions subject to current or expected future environmental regulation; and water consumption quantities and rates.
2. For the power supply system for the previous calendar year:
   a. A description of unit commitment procedures,
   b. Production cost,
   c. Reserve requirements,
   d. Spinning reserve,
   e. Reliability of generating, transmission, and distribution systems,
   f. Purchase and sale prices, averaged by month, for the aggregate of all short-term purchases and all short-term sales related to contracts of less than three years, and
   g. Energy losses.
3. The level of cogeneration and other forms of self generation in the utility's service area for the previous calendar year.
4. As available, a description and map of the utility's transmission system, including the

utility's scheduling capacity of each applicable segment of the transmission system. The map shall include both utility-owned transmission and the utility's long-term contractual transmission rights used to meet the resource needs of customers.

5. Explanation of exceptions from using an RFP for procurement of resources, pursuant to R14-2-705.B., during the previous calendar year.

C. Demand forecasts. Each utility shall provide the following data and analyses to the Commission by April 1, 2010, and every two years thereafter. If no changes are forecast for any item, the utility may refer to previous filings for that item.

1. A forecast of system coincident peak load (megawatts) and energy consumption (megawatt hours) for at least ten years, by month and year, separately for residential, commercial, industrial, interruptible, and other customers, for resale, and for energy losses.
3. Disaggregation of the demand forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component indicating the change in load due to forecasted demand management measures.
4. Descriptions of demand management programs and measures included in the demand forecast, including:
   a. Plans for implementing the demand management measures,
   b. The participation rate of customers by customer class with regard to each demand management measure,
   c. The expected change in demand resulting from each of the measures,
   d. Reductions in air emissions and water consumption attributable to the demand management program, and
   e. The life of each program.
5. Description of each demand management program which was considered but rejected and the reasons for rejecting each program.
6. The capital and operating and maintenance costs of each demand management measure considered, including practical measures which were rejected.
7. Documentation of all data, analyses, methods, and assumptions used in making the demand forecasts, including:
   a. A description of how the forecasts were benchmarked,
   b. Justifications for selecting the methods and assumptions used, and
   c. If requested by the staff, data used in the analyses.

D. Supply plans. Each utility shall provide the following data and analyses to the Commission by April 1, 2010, and every two years thereafter. If no changes are forecast for any item, the utility may refer to previous filings for that item.

1. A plan for at least ten years providing for each year:
   a. The data required in subsection (B)(1)(a) through (p) of this Section for each generating unit and purchased power source, and the data required in subsection (B)(2)(a) through (g) of this Section.
   b. For each generating unit that is new or refurbished during the period:
      i. The data required in subsection (B)(1) of this Section for applicable years, and
      ii. The capital cost, construction time, and construction spending schedule.
   c. The escalation levels assumed for each component of cost for each generating unit and purchased power source.
   d. For the discontinuation, decommissioning, or mothballing of any power source and

permanent deratings of any generating facility:

i. Identification of the power sources or units involved,
ii. The costs and spending schedule of such discontinuation, decommissioning, mothballing, or derating, and
iii. The reasons for discontinuation, decommissioning, mothballing, or derating.

e. The capital and operating and maintenance costs of new or refurbished transmission and distribution facilities, and a description of the need for and purpose of such facilities. The utility shall incorporate its most recent transmission plan filed pursuant to A.R.S. 40-360.02.A and any relevant provisions of the Commission's most recent decision on Biennial Transmission Assessment regarding the adequacy of transmission facilities in the state of Arizona.
f. Cost analyses and cost projections.

2. Documentation of the data, assumptions, and methods or models used to forecast production costs and power production in subsection (D)(1) of this Section, including the method by which the forecast was calibrated or benchmarked.
3. Description of each potential power source which was rejected, the capital and operating and maintenance costs of each rejected source, and the reasons for rejecting each source.
4. A forecast for at least ten years of cogeneration and other self generation by customers of the utility in terms of annual peak production (megawatts) and annual energy production (megawatt hours).
5. Disaggregation of the forecast of subsection (D)(4) of this Section into a component in which no additional efforts are made to encourage such generation, and a component consisting of the change in supply due to additional forecasted cogeneration and self generation measures.
6. A forecast for at least ten years of capital and operating and maintenance costs by year of all cogeneration and other self generation included in subsection (D)(5) of this Section.
7. Documentation of the analysis of cogeneration and other self generation in subsection (D)(4) through (6) of this Section.
8. A plan to consider generation using a diverse range of fuels and technologies, including nuclear and renewable resources.
9. Calculation of the benefits of renewable resources.
10. Calculation of costs to back-up renewable resources.
11. A plan to increase the efficiency of the utility's fossil fuel generation.
12. Data to support technology choices for supply-side resources.

E. Analyses of uncertainty. Each utility shall provide to the Commission the following information by April 1, 2010, and every two years thereafter:

1. Analyses using appropriate methods such as sensitivity analyses and probabilistic analyses, to assess errors and uncertainty in:
   a. Demand forecasts,
   b. The costs of demand management measures and power supply,
   c. The availability of sources of power,
   d. The costs of complying with existing and expected environmental regulations.
   e. Any analysis that the utility has done in consideration of the likelihood of additional or enhanced environmental requirements,
   f. Changes in fuel prices and fuel availability, and
   g. Other factors which the utility wishes to consider.

2. Identification of those options which enable the utility to best respond to significant changes in conditions where future characteristics are uncertain, including:
   a. Continual monitoring of critical variables and making commensurate changes in plans if those variables deviate significantly from the forecast,
   b. Building several smaller units instead of one large unit,
   c. Participating in regional generation and transmission projects, and
   d. Conducting well monitored pilot programs.

F. Integrated resource plan. Each utility shall provide the Commission with an integrated resource plan by April 1, 2010, and every two years thereafter containing:
   1. The plan or flexible set of plans for at least ten years which, on the basis of the analyses required in this Article, including the uncertainty analysis, will tend to minimize the present value of the total cost of meeting the demand for electric energy services.
   2. Complete description and documentation of the resource plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized.
   3. An action plan indicating the supply and demand-related actions to be undertaken by the utility over the next two years in furtherance of the integrated resource plan.
   4. A comprehensive, self-explanatory load and resources table summarizing the utility's plan.
   5. A brief executive summary.
   6. An index to indicate where the filing requirements can be found.
   7. Definitions of terms.

G. Work plan. Each utility shall file in Docket Control a work plan no later than twelve months prior to the due date of an integrated resource plan. The work plan shall include:
   1. An outline of the content of the integrated resource plan to be developed by the utility,
   2. The utility's method and assumptions for assessing potential resources, and
   3. An outline of the timing and extent of public participation and advisory group meetings to be held prior to the completion and filing of the integrated resource plan.

R14-2-704. Commission review of utility plans

A. Within 120 days of the submission of demand forecasts, supply plans, uncertainty analyses, and integrated resource plans by the utilities, the Commission shall schedule a hearing or hearings to review utility filings and to determine whether to order an acknowledgment of the integrated resource plan. Acknowledgment of a plan means ~~only~~ that the plan seems reasonable to the Commission at the time the acknowledgment is given. No particular ratemaking treatment shall be implied nor inferred by the Commission's acknowledgement. <u>The Commission will give considerable weight to the utility's actions that are consistent with an acknowledged integrated resource plan in a rate case or other proceeding.</u>

B. The Commission may request additional analyses to be conducted by the utilities to improve specified components of the utilities' analyses.

C. In making its acknowledgment determination, the Commission shall consider the following factors:
   1. The total cost of electric energy services.
   2. The degree to which the factors which affect demand, including demand management, have been taken into account.
   3. The degree to which non-utility supply alternatives, such as cogeneration and self generation, have been taken into account.

4. Uncertainty in demand and supply analyses, forecasts, and plans, and the flexibility of plans enabling response to unforeseen changes in supply and demand factors.
5. The reliability of power supplies.
6. The reliability of the transmission grid.
7. The degree to which a utility considered all relevant resources, risks and uncertainties.
8. The degree to which the utility's plan for future resources is in the best interest of customers.
9. The best combination of expected costs and associated risks for the utility and its customers.

D. The Commission will consider the information reported in the integrated resource plan when it evaluates the performance of the utility in rate and other proceedings.

E. A utility may seek Commission approval of specific resource planning actions.

R14-2-705. Procurement

A. The following procurement methods are considered to be acceptable for the wholesale acquisition of energy, capacity, and physical power hedge transactions:
1. Purchases through third party, on-line trading systems, including but not limited to the Intercontinental Exchange, Bloomberg, California Independent System Operator, New York Mercantile Exchange, or similar on-line third party systems.
2. Purchases from qualified, third party, independent energy brokers.
3. Purchases from non-affiliated entities through auctions or a request for proposals (RFP) process.
4. Bilateral contracts with non-affiliated entities.
5. Bilateral contracts with affiliated entities, provided that non-affiliated entities are provided notice of and an opportunity to beat any proposed contract before executing the transaction.
6. Any other competitive procurement process approved by the Commission.

B. Utilities shall use an RFP as the primary acquisition process. Exceptions may include the following:
1. For emergencies.
2. For short-term acquisitions to maintain system reliability.
3. For other components of energy procurement, such as transmission projects, fuels, and fuel transportation.
4. When the planning horizon is two years or less.
5. When a utility encounters a genuine, unanticipated opportunity to acquire a power supply resource at a clear and significant discount, when compared with the cost of acquiring new generating facilities, that will provide unique value to customers.
6. For transactions that satisfy obligations under the Renewable Energy Standard rules and for demand-side management/demand response programs.

C. An independent monitor shall be used in all RFP processes for procurement of new resources.

D. The utility shall consult with staff and jointly select three to five companies or consultants (vendor list) who can serve as an independent monitor.

E. The utility shall file its vendor list in Docket Control for interested parties' review. Parties will have 30 days to object to a vendor's inclusion on the list.

F. Within 60 days of the filing of the vendor list, staff shall identify the vendors it determines are appropriate. Once the vendors are identified by staff, the utility would be able to retain any of the authorized vendors for future RFPs. The utility shall provide written notice to staff of its retention of the independent monitor.

G. The utility shall enter into a contract with the monitor and shall pay the monitor. Reasonable bidders' fees may be used to help offset these costs. When appropriate, the utility may request recovery of its payments to the monitor in customer rates.

H. One week prior to the deadline for submitting bids, the utility shall provide the independent monitor with a copy of any bid proposal prepared by the utility or its affiliate, or any benchmark or reference cost the utility has developed against which to evaluate the bids. The independent monitor shall take steps to secure the utility bid or benchmark price in a location not known or accessible to any of the bidders or the utility or its affiliate.

I. The independent monitor shall provide reports, at least monthly, to staff throughout the RFP process.